BIG WEST OF CALIFORNIA, LLC
A FLYING J Company

6451 Rosedale Highway • Bakersfield, CA 93308 • Phone 661.326.4200 • www.flyingj.com

Electronic Mail and Certified Mail
7007 0710 0005 2066 8744

August 25, 2008

Mr. George Robin
Ground Water Office WTR-9
US EPA Region 9
75 Hawthorn Street
San Francisco, CA 94105-3901

RE: Review and Comment on Draft Permit
CA10600003

Dear Mr. Robin:

Thank you for your e-mail dated August 8, 2008, allowing Big West of California, LLC (Big West) the opportunity to review and comment on the draft UIC permit for Class I Nonhazardous Injection Wells, both proposed and currently in operation under permit by California Regional Water Quality Control Board – Central Valley Region (RWQCB).

Your email presented three particular items for which you wished to receive feedback, which are addressed below:

1. "[C]omments from Big West regarding whether the material you submitted during our review process is technically and correctly represented."

   Big West is confident that the material submitted during the review process has indeed been technically and correctly represented.

2. Does Big West "have any issues at this point concerning compliance with the terms of the permit?"

   Big West does not have any concerns over the ability to comply with the terms of the permit, except as are presented in the suggested changes to the document, and presented in topics for further discussion below.

3. "[P]rovide the method by which you will name/number the wells."

   Big West will name the new wells using the convention of "Lease Name," the designation "WD," then follow with the next corresponding value in numerical sequence of disposal wells within that particular lease. Examples using this format might be Fee WD-1 or Red Ribbon WD-4.

Big West has reviewed the draft permit and has incorporated a number of suggested changes using the redline/strikeout "track changes" tool in Microsoft Word. Further, Big

West has inserted several comments throughout the document using the "Insert Comment" feature; each of these is noted below, as well.

a. Part I, Paragraph 3 - Big West would like to discuss this paragraph with EPA to understand the intent and particular wording used as it relates to nearby oilfield operations.

b. Part I and Part II, Section G - Big West would like to discuss the duration of the permit and understand why a 10-year limit is imposed. No such duration exists within the existing RWQCB-issued permit.

c. Part II, Section A, Paragraph 4 (a) - Big West would like to understand how EPA exercises the discretion to require additional Step Rate Tests and on what wells to perform an SRT.

d. Part II, Section A, Paragraph 4 (b) - Big West would like to understand how EPA determines what is a "representative well."

e. Part II, Section A, Paragraph 5 (b) - Big West believes adding this reference to paragraph 10 (a) helps clarify that the daily drilling logs are to be reported to EPA by inclusion in the Well Completion Report. Is this correct?

f. Part II, Section A, Paragraph 9 (b)(i)(v) – Big West would like to further discuss this level of accuracy. Also, is EPA suggesting that a third party certify the gauges? If so, on what frequency?

g. Part II, Section A, Paragraph 9 (b)(ii) – Big West would like to discuss further this level of accuracy. This is not achievable throughout the full range of injection pressures with the technology currently utilized on Big West's current wells. Also, is EPA suggesting that a third party certify the gauges? If so, on what frequency?

h. Part II, Section C, Paragraph 2 (a) (i) - Big West would like to understand why the required test pressure is so high. Historically Big West has performed these tests, as required by the existing RWQCB-issued permit at a pressure of approximately 1000 psi.

i. Part II, Section C, Paragraph 2 (a) (ii) - This requirement for accuracy to 1 psi conflicts with requirements of Section D Paragraph 3 (a) which calls for accuracy to one-tenth of the unit of measure, or in this case 0.10 psi.

j. Part II, Section C, Paragraph 2 (c) (iii) - Big West would like to understand how "significant" is defined.

k. Part II, Section C, Paragraph 3 - See comment (a) related to this same concept and particular wording used in reference to nearby oilfield operations.

l. Part II, Section C, Paragraph 4 (a) - Big West would like to discuss how the injection volume is determined, how the limitation is imposed (cumulatively or per well) and at what point will this determination take place. Ensuring adequate disposal capacity is critical to the ongoing, uninterrupted operations of the refinery.

m. Part II, Section C, Paragraph 5 (c) - Big West would like to further discuss with EPA the authorization to do routine well stimulations with pre-determined, approved stimulation fluids without seeking approval prior to each event. Big West previously submitted data on proposed fluids to be used for routine stimulations, as needed, without seeking approval from EPA on a case-by-case basis. Big West would propose to seek advance approval for non-routine stimulations outside the pre-determined, EPA-approved parameters.

n. Part II, Section D, Paragraph 3 (a) - Big West would like to discuss the specific units of measure and clarify particular points in this paragraph such as cumulative flow and "immediately" before the wellhead. Additionally, Big West would like to discuss the level of accuracy in measurements (i.e. $1/10^{th}$ of unit of measure conflicts with other requirements in permit). Lastly, Big West would like to discuss technologies currently used and in place for gathering and recording this data versus the requirement for digital instrumentation as noted in this paragraph.

o. Part II, Section D, Paragraph 3 (a) - Big West is unclear on what "four words" this is referring to.

Big West requests an opportunity to meet with EPA representatives to discuss these particular items, as well as pertinent comments that EPA has received from other parties, such as RWQCB and California Department of Oil, Gas & Geothermal Resources. Please respond with one or more suggested times that would be convenient for EPA staff to participate in such a session.

Should there be a need for any additional information or questions pertaining to the comments provided here, please do not hesitate to contact me at (661) 326-4412 or Melinda Hicks, Senior Environmental Engineer, at (661) 326-4422.

Sincerely,

Bill Chadick
HSE Director

Attachment

cc: Mr. David Albright, US EPA Region 9, Manager Ground Water Office
Mr. Randy Adams, California Division of Oil, Gas and Geothermal Resources
Mr. Lonnie Wass, California Regional Water Quality Control Board
Ms. Melinda Hicks, Big West of California LLC
Mr. Gene Cotten, Big West of California LLC
Mr. Brad DeWitt, Petrotech Resources Company

MLH
V:ehs/private/wat/big west.../Class I Draft Permit Review Cover Ltr 082508.doc
File: 780,830

U.S. EPA Underground Injection Control Program

DRAFT PERMIT

Class I Nonhazardous Waste Injection Wells

Permit No. **CA10600003**

Well Names:
Existing Wells Red Ribbon WD-1, Red Ribbon WD-2, Red Ribbon WD-3 and WI-1
Up to Nine (9) Proposed Wells
Plugging and Abandonment (P&A) of Red Ribbon 7

Kern County, CA

Issued to:

Big West of California, LLC
6451 Rosedale Highway
Bakersfield, CA 93308

TABLE OF CONTENTS

PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR), §§124, 144, 145, 146, 147, and 148,

Big West of California, LLC
6451 Rosedale Highway
Bakersfield, CA 93308

is hereby authorized to, contingent upon Permit conditions, construct and operate a Class I nonhazardous waste injection facility with five (5) existing wells, nine (9) new wells to be drilled and one (1) well to be permanently plugged and abandoned (P&A) for a maximum of thirteen (13) injection wells. The existing wells are located within the boundaries of the Fruitvale Oilfield in Bakersfield in Section 27, Township 29S, Range 27E, for wells Red Ribbon WD-1, Red Ribbon WD-2, Red Ribbon WD-3 and Red Ribbon 7 (to be P&A) and in Section 23, Township 29S, Range 27E, for well WI-1, on Big West of California, LLC (Big West) facilities in Kern County, California. The nine (9) proposed wells are to approved be located in Sections 14, 15, 22, 23, 27 and 28 Township 29S, Range 27E. Exact locations of each proposed well will be established and approved as outlined within this permit.

Authorization to drill and construct the nine new wells will be issued by EPA after the requirements of Financial Responsibility in Part II, Section F of this permit have been met. EPA will grant authorization to inject after the requirements of Part II Sections A-C of this permit have been met. Operation of ~~both~~ the wells will be limited to maximum volume and pressure as stated in this permit. Total amounts must not exceed specified limits.

No injection fluids from Big West will be allowed to migrate to any nearby oilfield production wells. Further, this permit requires systematic and predictive documentation over the life of the facility's operation to ensure that no injection fluids – either presently nor in the future will migrate to oilfield operation production wells.[mlh1]

If approved, injection for Wells Red Ribbon WD-1, WD-2 and WD-3 will be authorized into the Lower Santa Margarita sand unit interval; injection for Well WI-1 will be authorized into the Fairhaven, Etchegoin, Chanac and Upper Santa Margarita sand unit intervals; injection for the nine (9) new wells will be authorized into the Etchegoin through the Lower Santa Margarita sand unit interval. These wells are to be completed for the purpose of disposal of industrial nonhazardous refinery waste fluids produced by Big West facilities.

All conditions set forth herein are based on Title 40 §§124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations.

This permit consists of ~~twenty-eight (28) pages~~ plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by Big West of California, LLC (Permittee or simply Big West) and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit.

This permit and the authorization to construct, test, and inject are issued for a period of ten (10) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.[mlh2]

This permit is issued and becomes effective on _____.

_____

Alexis Strauss, Director
Water Division, EPA Region IX

PART II. SPECIFIC PERMIT CONDITIONS

Prior to each demonstration required in the following sections A through C, the Permittee shall submit plans for procedures and specifications to the U.S. Environmental Protection Agency Region IX Ground Water Office, WTR-9 ("EPA") for discussion and approval. The submittal address is provided in Section D, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA. The Permittee shall submit results of each demonstration required in this section to EPA within sixty (60) days of completion.

A. WELL CONSTRUCTION

1. Requirement for Prior Written Permission to Drill, Test, Construct, or Operate

   (a) Financial Assurance

   The Permittee shall supply evidence of financial assurance prior to commencing Injection Well Drilling and Construction, in accordance with Section F of this part.

   (b) Pre-notification

   After approval for any of the approved field demonstrations is provided, notification to EPA at least 30 days prior to performing the demonstration is required, to allow EPA to arrange to witness if so elected.

2. Locations of Injection Wells

   Injection wells authorized under this permit will be located near the Big West property at 6451 Rosedale Highway in Bakersfield, California. The proposed general location for the nine (9) new wells is found in Appendix A.

   (a) Prior to drilling any well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude).

   (b) The Permittee shall submit a detailed ~~Prognosis~~ Program for each drilling or workover operation for EPA review and approval before the work will be allowed to be scheduled and conducted. Permitee may commence work as proposed in the Program if no reply is received from EPA within 45 days of Program submittal.

   (c) After drilling is completed, the Permittee must submit final field coordinates (Section, Township, Range, with latitude/longitude) of any well constructed under this permit with the Final Well Construction Report required under paragraph 12 of this section. If final well coordinates differ from the proposed coordinates submitted under paragraph (a), justification and

documentation of any communication with and approval by EPA shall be included.

3. Testing during Drilling and Construction

Logs and other tests conducted during drilling and construction shall include, at a minimum, deviation checks, casing logs, and injection formation tests as outlined in 40 CFR §146.12(d). Open Hole logs shall be conducted over the entire open hole sequence below the conductor casing. Permittee shall conduct Formation Evaluation wireline logging operations and provide those results. These logs will provide results that shall be used to estimate and report values for hydrocarbon saturation, porosity, lithology, formation dip direction, rock mechanical properties for both the injection zones and confining zones identified within the permitted geological sequence. These results shall be addressed and updated in a report within 60 days of receipt of all data reports following completion of drilling and construction of each well.

4. Injection Formation Testing

Injection formation information as described in 40 CFR 146.12 (e), shall be determined through well logs and tests and shall include porosity, permeability, static formation pressure, and effective thickness of the injection zone. A summary of results shall be submitted to EPA with the Final Construction Report required in paragraph 12 of this section.

(a) Step-Rate Test ("SRT")

An SRT will be conducted on representative well(s) approved by EPA before injection is authorized, to establish maximum injection pressure. Refer to Society of Petroleum Engineering ("SPE") paper #16798 for test design and analysis. Similar testing may be required in other wells, at the discretion of EPA. The SRT will be used to establish the injection pressure limitation, in accordance with section C, paragraph 3 of this part. Permittee must submit detailed plans for conducting the SRT for EPA review and approval before the SRT will be allowed to be scheduled and conducted. Permitee may commence work as proposed in the plans if no reply is received from EPA within 45 days of SRT detailed plans submittal.[mlh3]

Detailed plans will include at a minimum the following:

(i) Prior to testing, shut in the well long enough so that the bottom-hole pressure approximates shut-in formation pressure.

(ii) Measure pressures with a down-hole pressure ~~bomb~~ recorder and coordinate with a surface pressure recorder.

(iii) Use equal-length time step intervals throughout the test; these should be sufficiently long to overcome well bore storage and to achieve radial flow. Intervals may need to be more, but must be no less than thirty (30) minutes in duration.

(iv) Use 1 (one) bbl per min rate increments in the early stages. Larger rate increments may be used later in the test, however the reasons for this request must be approved. This also allows for the requirement to record at least three (3) time steps (data points on pressure vs. flow plot) before reaching the anticipated fracture pressure.

(v) At the end of the test, shut down pumps and record the instantaneous shut in pressure and observe the pressure falloff for a sufficient time period to observe and later analyze the radial flow portion of the injection zone during the SRT. The length of time for pressure falloff observation must be determined and discussed in the Permittee's submission plans in advance of conducting the SRT.

(b) Fall Off Pressure Test ("FOT")

To determine and to monitor formation characteristics, a FOT shall be run in the representative well for each injection formation-pressure system determined by EPA [mlh4]after radial flow regimes have been established. FOTs shall be conducted in accordance with EPA Region 9 Guidance found in Appendix E. The Permittee shall use the test results to recalculate the Zone of Endangering Influence ("ZEI", as defined in 40 CFR §146.6) and to evaluate whether any corrective action is now required (refer to Section B of this part); a summary of the recalculation shall be included with the FOT report. Detailed plans for conducting the FOT must be submitted to EPA for review, possible editing, and approval. Once approved, Permittee may schedule the FOT, providing EPA at least 30 days notice before the FOT is conducted.

(i) Initially, a FOT shall be run in at least one representative well after a radial flow regime has been established at an injection rate that is representative of the facility's wastewater generation rate.

(ii) Annually thereafter, the FOT test shall be repeated and results shall be included within 60 days of receipt of all data reports. The annual FOT should not be less than 9 months or greater than 15 months from the previous test.

(iii) The latest static reservoir pressure and its cumulative behavior on a graphic plot of the injection zone shall be determined and reported with the FOT report in paragraphs (i) and (ii) above.

(c) Particulate Filters may be used upstream of the well, at the discretion of the operator, to prevent formation plugging or damage from particulate matter. Include any filter specifications in the Final Construction Report required in paragraph 12 of this section, including proposed particle size along with any associated justification.

(i) For any particulate filters used, follow appropriate waste analysis and disposal practices.

5. Drilling, Work-over, and Plugging Procedures

Drilling, work-over, and plugging procedures must comply with the California Division of Oil, Gas, and Geothermal Resource's ("CDOGGR") "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Section 1722-1723. Drilling procedures shall also include details for:

(a) Details for staging long-string cementing or justification for cementing without staging; and

(b) Reporting to EPA, as required by paragraph 10 (a), shall include records of Daily Drilling Reports (electronic and hard copies);[mlh5]

(c) Casing and other tubular and accessory measurement tallies;

(d) Blowout Preventer (BOP) System tests must be on recording charts with complete explanatory notes throughout the tests.

CDOGGR reporting forms such as Well Summary Report, etc. may be accepted provided they contain all information as required within this permit.

6. Casing and Completion Specifications

Notwithstanding any other provisions of this permit, the Permittee shall case and cement the proposed wells to prevent the movement of fluids into or between USDWs. Cement evaluation analyses shall be performed as described in Section C paragraph 2(a)(iv) of this part. Casings shall be maintained throughout the operating life of the wells. The specifications from the permit application apply to the existing wells and to the proposed wells in Appendix B:

7. Injection Intervals

Existing Wells in the Lower Santa Margarita:
Red Ribbon WD-1 perforation interval 5,135-5,525 ft

Red Ribbon WD-2 perforation interval 5,097-5,104; 5,126-5,256; 5,161-5,174; 5,186-5,200; 5,231-5,241; 5,346-5,440 and 5,644-5,684 ft
Red Ribbon WD-3 perforation interval 5,000-5,525 ft

Existing Well in the Etchegoin/Chanac/Santa Margarita:
WI-1 perforation interval 3,220-3,260; 3,280-3,490; 3,560-3-640; 60 Mesh slots 3,595-4,099; 60 Mesh slots 3,665-3,685 and 3,705-4,402 ft

Plug and Abandon Red Ribbon #7

Proposed Wells in Sections 27 and 28 (vertically drilled)
Lower Santa Margarita perforations 5,000-5,525 ft
Etchegoin/Chanac/Santa Margarita perforations 3,300-5,525 ft

Proposed Wells in Sections 27 and 28 (horizontally drilled, vertical depths of perforations)
Lower Santa Margarita perforations 5,000-5,525 ft
Etchegoin/Chanac/Santa Margarita perforations 3,300-5,525 ft

Proposed Wells in Sections 14, 15, 22 and 23 (vertically drilled)
Lower Santa Margarita perforations 4,400-4,925 ft
Etchegoin/Chanac/Santa Margarita perforations 3,320-4,925 ft

Proposed Wells in Sections 14, 15, 22 and 23 (horizontally drilled vertical depths of perforations)
Lower Santa Margarita perforations 4,400-4,925 ft
Etchegoin/Chanac/Santa Margarita perforations 3,320-4,925 ft

There may be minor alterations of the depths at which the injection zone intervals are actually encountered and therefore, the casing setting depths are expected to be realized upon drilling. Final depths will be determined by the field conditions, pilot boring cuttings, sieve analysis, well logs, fluid tests and other input from the drilling consultant and hydrogeologist. EPA approval will be obtained, in advance, for any revisions. These alterations and other rework operations that may occur later in the course of operation of the wells are considered minor for this permit and must be properly reported (use EPA Form 7520-12). The Permittee must demonstrate that each well has mechanical integrity, in accordance with Section C paragraphs 1(a) and 2 of this part, before any injection is authorized.

8. Confining Layer

Field information on each of the confining layers, the Shale immediately overlying the injection zones (Etchegoin/Chanac/Santa Margarita or Lower Santa Margarita), such as its characteristics, its thickness and its local structure will be obtained during

drilling of the proposed injection wells and and a full description shall be included in the Final Well Construction Report required in paragraph 12 of this section.

9. Monitoring Devices

The Permittee shall install and maintain in good operating condition:

(a) A tap on the discharge line between the injection pump and the wellhead for the purpose of obtaining representative samples of injection fluids; and

(b) Devices to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volumes, subject to the following:

(i) Pressure gauges shall be of a design to provide:

(iv) A full pressure range of 100 percent greater than the anticipated operating pressure; and

(v) A certified deviation accuracy of five (5) percent or less throughout the operating pressure range.[mlh6]

(ii) Flow meters shall measure cumulative volumes and be certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the permit.[mlh7]

10. Final Well Construction Report and Completion of Construction Notice

(a) The Permittee must submit a final well construction report, including logging, coring, and other results, with a schematic diagram and detailed description of construction, including drilling engineer's log, materials used (i.e., tubing tally), and cement (and other) volumes, to EPA within sixty (60) days of receipt of all data reports after completion of each new injection well and following each workover operation.

(b) The Permittee must also submit a notice of completion of construction to EPA (see EPA Form 7520-9 in Appendix C). Injection operations may not commence until EPA has inspected or otherwise reviewed the injection wells and notified the Permittee that it is in compliance with the conditions of the permit. CDOGGR reporting forms such as Well Summary Report, etc. may be accepted provided they contain all information as required within this permit.

11. Proposed Changes and Workovers

The Permittee shall give advance notice to EPA, as soon as possible, of any planned physical alterations or additions to the permitted injection wells. Any changes in well construction require prior approval of EPA and may require a permit modification under the requirements of 40 CFR §§144.39 and 144.41. In addition, the Permittee shall provide all records of well workovers, logging, or other subsequent test data, including required mechanical integrity testing, to EPA within sixty (60) days of reciept of all data reports following completion of the activity. Appendix C contains samples of the appropriate reporting forms. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section C paragraphs 1(a) and 2 of this part.

B. CORRECTIVE ACTION

Corrective action to 40 CFR §§144.55 and 146.7 may be necessary for existing wells in the Area of Review ("AOR", defined in 40 CFR §146.6) that penetrate the injection zone, or which may otherwise cause movement of fluids into non-exempt USDWs. No corrective action plan is currently required, since no known wells located within the AOR penetrate the proposed zones of injection. See Appendix A.

1. Initial ZEI re-evaluation with Field Data

Data resulting from testing performed under Section A paragraphs 4 and 5, or Section C paragraph 2, in this part will be used to confirm or modify assumptions used to calculate the original ZEI and to set the AOR. If new field data results in a ZEI larger than the AOR which includes wells penetrating the proposed zones of injection, a corrective action plan shall accordingly be proposed for approval and implemented as described in paragraph 3 of this section.

2. Annual ZEI Review

Annually, the ZEI calculation shall be reviewed and modified if based on any new data obtained from the FOT(s) and static reservoir pressure tests required in Section A, paragraphs 5(d) and (e) of this part. A copy of the reviewed ZEI calculations, along with all associated assumptions or justifications, shall be provided to EPA with the quarterly report due in January, as required in Section D paragraph 5 of this part.

3. Implementation of Corrective Actions

(a) If any wells requiring corrective action are found within the modified ZEI, a list of these wells along with their locations shall be provided to EPA with the quarterly report or within 60 days whichever is sooner.

(b) If requested by EPA, the Permittee shall submit a plan to re-enter, plug, and abandon the wells listed in paragraph (a) above in such a manner to prevent the migration of fluids into a USDW.

(c) The Permittee may not commence corrective action activities without prior written approval from EPA.

C. WELL OPERATION

1. Demonstrations Required Prior to Injection

Injection operations may not commence until construction is complete and the Permittee has complied with following paragraphs (a) and (b):

(a) Mechanical Integrity

The Permittee shall demonstrate that all wells have and maintain mechanical integrity consistent with CFR §146.8 and with paragraph 2 of this section. The Permittee shall demonstrate that there are not significant leaks in the casing and tubing and that there is not significant fluid movement into or between USDWs through the casing wellbore annulus or vertical channels adjacent to the injection wellbore. The Permittee may not commence injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Injectate Hazardous Waste Determination

The Permittee shall perform a "Hazardous Waste Determination" according to 40 CFR §262.11. The results of the waste determination shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR §§ 146.3 and 261. In addition:

(i) The Permittee shall maintain copies (or originals) of all records relating to the "Hazardous Waste Determination" and make such records available for inspection. In addition, the Permittee will be required to submit a letter to EPA confirming that the "Hazardous Waste Determination" was carried out according to 40 CFR §262.11 within sixty (60) days of its having been completed.

(ii) The Permittee shall perform an additional "Hazardous Waste Determination" whenever there is a process change or a change in fluid chemical constituents or characteristics.

2. Mechanical Integrity

(a) Mechanical Integrity Tests ("MITs")

(i) Casing/tubing annular pressure (internal MIT)

A demonstration of the absence of significant leaks in the casing, tubing and/or liner hanger shall be made by performing a pressure test on the annular space between the tubing and long string casing. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable injection pressure.[mlh8] A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A pressure differential of at least 350 pounds per square inch ("psi") between the tubing and annular pressures shall be maintained throughout the MIT.

(ii) Continuous pressure monitoring

The tubing/casing annulus pressure and injection pressure shall be monitored and recorded continuously to an accuracy within one (1) psi. [mlh9]The average, maximum, and minimum monthly results shall be included in the quarterly report to EPA unless more detailed records are requested by EPA.

(iii) Injection profile survey (external MIT)

In conjunction with the FOT required in Section A paragraph 4(c), a demonstration that the injectate is confined to the proper zone shall be conducted and presented by the Permittee and subsequently approved by EPA. This demonstration shall consist of a radioactive tracer and a temperature log or other diagnostic tool or procedure as approved by EPA. Detailed plans for executing the external MIT shall be submitted to EPA for review and approval before being allowed to be scheduled and conducted. See Appendix D Temperature Logging Requirements

(iv) Cement Evaluation Analysis

After casing is installed, or after conducting a cement squeeze job, for any well constructed under this permit, the Permittee shall submit cementing records and cement evaluation logs that demonstrate the isolation of the injection interval and other formations from underground sources of drinking water by means of cementing the surface casing and the long string casing well bore annuli to surface. The analysis shall include a spherically-focused tool which enables the evaluation of the bond between cement and casing as well as of

the bond between cement and formation. The Permittee may not commence injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Subsequent MITs

It is the Permittee's responsibility to arrange and conduct MITs.

(i) At least once every five (5) years during the life of the well, in accordance with 40 CFR §146.8 and paragraph (a)(i) above, an internal pressure MIT shall be conducted on each injection well authorized under this permit. An MIT shall also be conducted within thirty (30) days from completion of any work-over, if the liner hanger is unseated, if the seal is broken at the wellhead assembly, if the construction of the well is modified, or when any loss of mechanical integrity becomes evident during operation. In addition, EPA may require that an MIT be conducted at any time during the permitted life of the wells.

(ii) At least annually for the life of each well, an injection profile survey external MIT, in accordance with 40 CFR §146.8 and paragraph (a)(ii) above, shall be conducted.

(iii) At least annually, FOT(s) shall be conducted in accordance with Section A paragraph 5(d) of this part, unless other information demonstrates the need for additional tests and/or an increased frequency of tests. The proposed procedures must generally conform to EPA regional guidance for conducting pressure falloff tests but must be adapted for the specific conditions at this facility. Detailed plans for conducting the FOT must be submitted to EPA for review, possible editing, and approval. Permittee may commence work according to the detailed plans if no reply has been received from EPA within 45 days of plan submittal. Once approved, Permittee may schedule the FOT, providing EPA at least 30 days notice before the external MIT is conducted. Appendix E contains Region 9 UIC pressure falloff testing requirements.

(c) Loss of Mechanical Integrity

The Permittee shall notify EPA, in accordance with Part III, Section E paragraph 10 of this permit, under any of the following circumstances:

(i) The well fails to demonstrate mechanical integrity during a test, or

(ii) A loss of mechanical integrity becomes evident during operation, or

(iii) A significant change in the annulus or injection pressure occurs during normal operating conditions[mlh10].

Furthermore, in the event of (i), (ii), or (iii), injection activities shall be terminated immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore mechanical integrity to the well and EPA gives approval to recommence injection.

(d) Prohibition without Demonstration

After the permit effective date, injection into wells may continue only if:

(i) The well has passed an internal pressure MIT in accordance with paragraph 2(a) of this section; and

(ii) The Permittee has received written notice from EPA that the internal pressure MIT demonstration is satisfactory.

3. Injection Pressure Limitation

Maximum allowable injection pressure measured at the wellhead shall be based on the Step-Rate Test conducted under Section C paragraph 5(b) of this part, or on results of previously conducted Step-Rate Tests. EPA will provide the Permittee written notification of the maximum allowable injection pressure for each injection well constructed and operated under this permit, along with a minor modification of the permit under 40 CFR §144.41(e). In no case shall pressure in the injection zone during injection initiate new fractures or propagate existing fractures in the injection zone or the confining zone. In no case shall injection pressure cause the movement of injection or formation fluids into or between underground sources of drinking water. In no case shall injection fluids be allowed to migrate to oilfield production wells.[mlh11]

4. Injection Volume (Rate) Limitation

(a) The injection rate shall not exceed the volume determined appropriate through the demonstrations conducted in this section and justified by the calculated or measured fluid friction. EPA will provide written notification of the maximum injection volume allowed under this permit prior to any injection activities.[mlh12]

(b) The Permittee may request an increase in the maximum rate allowed in paragraph (a) above. Any such request shall be made in writing and appropriately justified to EPA.

(c) Any request for an increase in injection rate shall demonstrate to the satisfaction of EPA that the increase in volume will not interfere with the operation of the facility, its ability to meet conditions described in this permit, change its well classification, or cause migration of injectate or pressure buildup to occur beyond the Area of Review.

5. Injection Fluid Limitation

(a) The Permittee shall not inject any hazardous waste, as defined by 40 CFR Part 261, at any time. See also paragraph 1(b) of this section.

(b) Injection fluids shall be limited to only waste fluids authorized by this permit and produced at the Big West facility. No fluids shall be accepted from other sources.

(c) Any well stimulation, performed at the discretion of the operator, shall be proposed and submitted to EPA for approval prior to implementation.[mlh13]

6. Tubing/Casing Annulus Requirements

(a) Corrosion-inhibiting annular fluid shall be used and maintained during well operation. A complete description and characterization shall be submitted to EPA for approval before use.

(b) A minimum pressure of 100 psi at shut-in conditions shall be maintained on the tubing/casing annulus. Within the first quarter of injection operations, Permittee shall determine the range of fluctuation of annular pressure that shall be considered normal for each well configuration during periods of injection. The results of this determination shall be submitted with the first quarterly report after injection operations have commenced. Any annular pressure behavior outside of the normal range of fluctuation shall be considered indicative of a loss of mechanical integrity (MI) and shall be reported as per Section C. paragraph 2.(c) of this part.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program

Injection fluids will be analyzed to yield representative data on their physical, chemical, and other relevant characteristics. The Permittee shall take samples at or before the wellhead for analysis. The results of the tests shall be submitted to EPA on a quarterly basis.

Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize applicable analytical methods described in Table I of 40 CFR

§136.3, or in Appendix III of 40 CFR §261, unless other methods have been approved by EPA.

(a) Summary of acceptable analytic Methods:

(i) Inorganic Constitutents – appropriate USEPA methods for Major Anions and Cations (including an anion/cation balance).

(ii) Solids - USEPA Methods 160.1 and 160.2 for Total Dissolved Solids and Total Suspended Solids.

(iii) General and Physical Parameters – appropriate USEPA methods for Turbidity, pH, Conductivity, Hardness, Specific Gravity, Alkalinity, Biological Oxygen Demand ("BOD"); Density and Viscosity (See EPA Bulletin 712-C-96-032) under standard conditions.

(iv) Trace Metals - USEPA Method 200.8 for trace metals analysis.

(v) Volatile Organic Compounds ("VOCs") - USEPA Methods 8010/8020 or 8240.

(vi) Semi-Volatile Organic Compounds - USEPA Method 8270.

(b) Analysis of injection fluids.

A sample of the injectate shall be taken by an individual with the proper expertise and sent to a laboratory with proof of certification from the State of California. Sampling and injectate analyses, performed as outlined in paragraph (a) above, must occur quarterly and every time there is a significant change in injection fluid, and shall be reported per section D paragraphs 5(a) through 5(d)(i) of this part.

2. Monitoring Information

Records of monitoring activity required under this permit shall include:

(a) Date, exact location, and time of sampling or field measurements;

(b) Name(s) of individual(s) who performed sampling or measuring;

(c) Exact sampling method(s) used;

(d) Date(s) laboratory analyses were performed;

(e) Name(s) of individual(s) who performed laboratory analyses;

(f) Types of analyses; and

(g) Results of analyses.

3. Monitoring Devices

(a) Continuous monitoring devices

Temperature, annular pressure, and injection pressure shall be measured at the wellhead using equipment of sufficient sensitivity and accuracy. All measurements must be recorded at minimum to a precision of one tenth of the unit of measure (e.g. injection rate and volume must be recorded to a precision of a tenth of a gallon; pressure must be recorded to a precision of a tenth of a psig; injection fluid temperature must be recorded to a precision of a tenth of a degree Fahrenheit). Exact dates and times of measurements, when taken, must be recorded and submitted. Injection rate, wellhead injection pressure, annular pressure and injection fluid temperature specifically must be recorded on an hourly basis. Injection rate shall be measured in the supply line immediately before the wellhead. The Permittee shall continuously monitor and record the following parameters at the prescribed frequency:

Continuously Monitored Parameter	Recording Frequency	Instrument
Injection rate (gallons per minute)	Hourly	digital recorder
Daily Injection Volume (gallons)	Daily	digital totalizer
Total Cumulative Volume (gallons)	Daily	digital totalizer
Well head injection pressure (psig)	Hourly	digital recorder
Annular pressure (psig)	Hourly	digital recorder
Injection fluid temperature (°F)	Hourly	digital recorder[mlh14]

The Permittee is required to adhere to the preferred format below for reporting injection rate and wellhead injection pressure. An example of this data format:

DATE	TIME	INJ. PRESS (PSIG)	INJ. RATE (GPM)
06/27/07	16:33:16	1525.6	65.8
06/27/07	17:33:16	1525.4	66.3

Each line with data has to include 4 words separated by any combination of spaces and tabs[mlh15]. The first column contains information about the measurement date in the format mm/dd/yy or mm/dd/yyyy , where mm is the month, dd is the day of the month and yy or yyyy is the year. The second column is the measurement time, in the format hh:mm:ss, where hh is the hour, mm are the minutes and ss are the seconds. Hours should be calculated on a 24 hours basis, i.e. 6 PM should be entered as 18:00:00. Seconds are optional. The third column is the well head injection pressure in psi. The fourth column is injection rate in gallons per minute.

(b) Calibration and Maintenance of Equipment

All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

4. Recordkeeping

The Permittee shall retain the following records and have them available at all times for examination by an EPA inspector:

(a) All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the permit application;

(b) Information on the nature and composition of all injected fluids;

(c) The results of performing the hazardous waste determination on the injectate according to 40 CFR §262.11. The results of the analyses shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR §261. Refer to Part II.C.1.(b) of this permit;

(d) Records and results of MITs, any other tests required by EPA, and any well workovers completed.

(e) The Permittee shall maintain copies (or originals) of all records described in paragraphs (a) through (d) above during the operating life of the well and shall make such records available at all times for inspection at the facility.

(f) The Permittee shall only discard the records described in paragraphs (a) through (d) if:

(i) the records are either delivered to the Regional Administrator or

(ii) written approval from the Regional Administrator to discard the records is obtained.

5. Reporting

Quarterly, the Permittee shall submit accurate reports in hard copy and electronic format as specified to EPA containing, at minimum, the following information:

(a) Monthly average, maximum, and minimum values for the continuously monitored parameters specified for the injection wells in paragraph 3(a) of this section, unless more detailed records are requested by EPA;

(b) Quarterly analyses, to be included in the next quarterly report following completion:

(i) Injection fluid characteristics for parameters specified in paragraph 3(b) of this section;

(ii) Hazardous waste injectate determination, according to Section C, paragraph 1(c)(i) of this part.

(c) Total cumulative injected volume over the course of the life of the well to date, unless more detailed records are requested by EPA;

(d) Quarterly analyses, to be included in the next quarterly report following completion:
ii. Injection fluid characteristics for parameters specified in paragraph 3(b) of this section;
ii. When appropriate, hazardous waste injectate determination, according to Section C, paragraph 1(b)(i) of this part.

(e) To be included with the next quarterly report immediately following completion of each well, results of any additional MITs or other tests required by EPA, and any well workovers completed; and

(f) To be included in the quarterly report due in January each year, the following annual analyses,:

(i) Annual reporting summary (7520-11 in Appendix C);

(ii) FOT results as required in Section A, paragraph 5(c) of this part;

(iii) Shut-in static reservoir pressure behavior plot of the injection zone, as required in Section A, paragraph 5(d) of this part;

(iv) Annual injection profile survey results as required in Section C paragraph 2(a)(iii) of this part; and

(v) Annual ZEI recalculation as required in Section B paragraph 2 of this part.

(e) To be included in the next quarterly report due in January after completion every five years, an internal MIT as required in Section C paragraph (a)(i) of this part.

(f) A narrative description of all non-compliance that occurred during the reporting period.

Quarterly report forms as specified in Appendix C shall be submitted for the reporting periods by the respective due dates as listed below:

Reporting Period	Report Due
Jan, Feb, Mar	Apr 28
Apr, May, June	July 28
July, Aug, Sept	Oct 28
Oct, Nov, Dec	Jan 28

Monitoring results and all other reports required by this permit shall be submitted to the following address:

U.S. Environmental Protection Agency, Region IX
Water Division
Ground Water Office (Mail Code WTR-9)
75 Hawthorne St.
San Francisco, CA 94105-3901

Copies (electronic on disks permissible) of all reports and correspondence shall also be provided to the following:

California Division of Oil, Gas, and Geothermal Resources
District 4 Office
Attn: Randy Adams
4800 Stockdale Hwy. Ste. 417
Bakersfield, CA 93309

California Regional Water Quality Control Board
Central Valley Region
Attn: Doug Patteson
1685 E Street
Fresno, CA 93706

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify EPA no less than sixty (60) days before ~~conversion, workover, or~~ abandonment of the well. EPA may require that the plugging and abandonment be witnessed by an EPA representative.

2. Plugging and Abandonment Plans

The Permittee shall plug and abandon the well(s) as provided in Appendix F, the general Plugging and Abandonment Program submitted as Attachment Q to the application, and consistent with CDOGGR requirements and 40 CFR §146.10. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life or if the well is not consistent with EPA requirements for construction or mechanical integrity. EPA may require the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the wells, including mud and disposal costs, with appropriate contingencies.

3. Cessation of Injection Activities

After a cessation of injection operations for two (2) years, the Permittee shall plug and abandon the inactive well(s) in accordance with the Plugging and Abandonment Plans, unless it:

(a) Provides notice to EPA;

(b) Has demonstrated that the well(s) will be used in the future; and

(c) Has described actions or procedures, satisfactory to EPA, that will be taken to ensure that the well(s) will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report

Within sixty (60) days of receipt of all data reports after plugging any well, the Permittee shall submit a report on Form 7520-13, provided in Appendix C, to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

(a) A statement that the well was plugged in accordance with the Plugging and Abandonment Plans, or

(b) Where actual plugging differed from the Plugging and Abandonment Plans, a statement specifying the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The Permittee is required to demonstrate and maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans and consistent with 40 CFR §144 Subpart D, which the Director has chosen to apply.

(a) The Permittee shall post a financial instrument such as a surety bond with a standby trust agreement or arrange other financial assurance in the amount of $2,435,961 plus $500,000 for each new well, to guarantee closure. Authority to inject or to drill and construct any well will not be given until the financial instrument has been posted and approved by EPA.

(b) The financial responsibility mechanism shall be reviewed and updated periodically, upon request of EPA. The permittee may be required to change to an alternate method of demonstrating financial responsibility which names EPA as the beneficiary. Any such change must be approved in writing by EPA prior to the change.

2. Insolvency of Financial Institution

The Permittee must submit an alternate instrument of financial responsibility acceptable to EPA within sixty (60) days after either of the following events occurs:

(a) The institution issuing the bond or financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

Failure to submit an acceptable financial demonstration will result in the termination of this permit pursuant to 40 CFR •144.40(a)(1).

3. Insolvency of Owner or Operator

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

G. DURATION OF PERMIT

This permit and the authorization to inject are issued for a period of up to ten (10) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant (as defined by 40 CFR §144.3) into underground USDWs (as defined 40 CFR §§144.3, 146.4), unless exempted, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons.

Furthermore, any underground injection activity not specifically authorized in this permit is prohibited. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act ("SDWA") and 40 CFR Parts 144, 145, 146, and 124. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this permit shall be construed to relieve the Permittee of any duties under all applicable laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

EPA may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§124.5, 144.12, 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the Permittee, does not stay the applicability or enforceability of any permit condition. EPA may also modify, revoke and reissue, or terminate this permit in accordance with any amendments to the SDWA if the amendments have applicability to this permit.

2. Transfers

This permit is not transferable to any person unless notice is first provided to EPA and the Permittee complies with requirements of 40 CFR §144.38. EPA may require modification or revocation and reissuance of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR §§2 and 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures contained in 40 CFR §2 (Public Information). Claims of confidentiality for the following information will be denied:

1. Name and address of the Permittee, or

2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply - The Permittee shall comply with all applicable UIC Program regulations and all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act ("RCRA").

2. Penalties for Violations of Permit Conditions - Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to enforcement actions pursuant to RCRA. Any person who willfully violates a permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense - It shall not be a defense, for the Permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate - The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance - The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Property Rights - This permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information - The Permittee shall furnish to EPA, within a time specified, any information which EPA may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry - The Permittee shall allow EPA, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

   (c) Inspect and photograph at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Signatory Requirements - All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §§122.22 and 144.32.

10. Additional Reporting

   (a) Planned Changes – The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.

   (b) Anticipated Noncompliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

   (c) Compliance Schedules - Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

(d) Twenty-four Hour Reporting

(i) The Permittee shall report to EPA any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances. The following information must be reported orally within twenty-four (24) hours:

(1) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; and

(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission of all noncompliance as described in paragraph (c)(i) shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(e) Other Noncompliance - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E.10(c) of this permit.

(f) Other Information - If the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Continuation of Expiring Permit

(a) Duty to Reapply - If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least 180 days before this permit expires.

(b) Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) until the effective date of a new permit, if:

(i) The Permittee has submitted a timely and complete application for a new permit; and

(ii) EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

APPENDIX A - PROJECT MAPS

APPENDIX B – WELL SCHEMATICS

APPENDIX C – EPA REPORTING FORMS
(The website for downloading these forms is at: http://www.epa.gov/safewater/uic/7520s.html)

Form 7520-7: Application toTransfer Permit

Form 7520-9: Completion of Construction

Form 7520-10: Well Completion Report

Form 7520-11: Annual Well Monitoring Report

Form 7520-12: Well Rework Record

Form 7520-14: Plugging and Abandonment Plan

APPENDIX D – TEMPERATURE LOGGING REQUIREMENTS
U.S.E.P.A. REGION IX

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid Mechanical Integrity Test ("MIT") as specified by 40 CFR §146.8(c)(1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log. As a general rule, the well shall inject for approximately six (6) months prior to running a temperature decay progression sequence of logs.

1. With the printed log, provide also raw data for both logging runs (one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is 12 hours for running the initial temperature log, followed by a second log, a minimum of 4 hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between 20 and 50 ft. per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
   (a) a collar locator log,
   (b) a lithology log:
      i. an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses; or
      ii. a copy of an original SP curve from either the subject well or from a representative, nearby well.
   (c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water ("USDW"). A USDW is basically a formation that contains less than 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

APPENDIX E - REGION 9 UIC PRESSURE FALLOFF TEST REQUIREMENTS

APPENDIX F - PLUGGING AND ABANDONMENT Schematics

Upon completion of injection activities the well(s) shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.

Page: 4
[mlh1]a. Big West would like to discuss this paragraph with EPA to understand the intent and particular wording used.
Page: 5
[mlh2]b. Big West would like to discuss the duration of the permit and better understand by a 10-year limit is imposed.
Page: 7
[mlh3]c. Big West would like to understand how EPA exercises the discretion to require additional Step Rate Tests.
Page: 8
[mlh4]d. Big West would like to understand how EPA determines what is a "representative well."
Page: 9
[mlh5]e. Big West believes adding this reference to paragraph 10(a) helps clarify that the daily drilling logs are to be reported to EPA by inclusion in the Well Completion Report. Is this correct?
Page: 11
[mlh6] f. Big West would like to discuss further this level of accuracy. Also, is EPA suggesting that the gauges be certified by a third party? If so, on what frequency?
Page: 11
[mlh7]g. Big West would like to discuss further this level of accuracy. This is not achievable throughout the full range of injection pressures with the technology currently utilized on Big West's current wells. Also, is EPA suggesting that the gauges be certified by a third party? If so, on what frequency?
Page: 14
[mlh8]h. Big West would like to understand why the required test pressure is so high.
Page: 14
[mlh9]i. This requirement for accuracy to 1 psi conflicts with requirements of Section D Paragraph 3 (a) which calls for accuracy to one-tenth of the unit of measure, or in this case 0.10 psi. Further, Big West would like to discuss with EPA the level of accuracy as it applies to the full scale of pressures.
Page: 16
[mlh10]j. Big West would like to understand how "significant" is defined.
Page: 16
[mlh11]k. See comment a related to this same concept and particular wording used.
Page: 16
[mlh12]l. Big West would like to discuss how the injection volume is determined, how the limitation is imposed (cumulatively or per well) and at what point will this determination take place.
Page: 17
[mlh13]m. Big West would like to further discuss with EPA the authorization to do routing well stimulations with pre-determined, approved stimulation fluids without seeking approval prior to each instance.
Page: 19
[mlh14]n. Big West would like to discuss the specific units of measure and clarify particular points in this paragraph such as cumulative flow and "immediately" before the wellhead. Additionally, Big West would like to discuss the level of accuracy in measurements (i.e. $1/10^{th}$ of unit of measure conflicts with other requirements in permit). Lastly, Big West would like to discuss technologies currently used and in place for gathering and recording this data versus the requirement for digital instrumentation as noted in this paragraph.
Page: 20
[mlh15]o. Big West is unclear on what "four words" this is referring to.

BIG WEST OF CALIFORNIA, LLC
TYPICAL ACIDS AND ADDITIVES
FOR WASTE WATER INJECTION WELL MAINTENANCE

15% HYDROCHLORIC ACID (HCl)

The acceptable range of strength is 13.5% to 16.5% HCl to effectively treat the wells. The actual volumes are calculated for each job but generally range amounts of about 10-20 gallons per foot of injection zone. These acids usually contain the additives listed below.

12% HYDROCHLORIC - 3% HYDROFLUORIC ACID (MUD ACID)

The acceptable range of strength is 11% to 13% HCl and 2.5% to 3.5% HF for effective treatment. The actual volumes are calculated for each job but generally range amounts of about 10-20 gallons per foot of injection zone. This acid should contain additives as specified below.

SODIUM HYPOCHLORITE (bleach)

Sufficient strength and volume to effectively kill and oxidize bacteria in the well. Fluid spacers and post flushes are used at the surface and in the well to ensure the sodium hypochlorite does not come into direct contact with hydrochloric acid. The actual volumes are calculated for each job but typically include the volume to fill the wellbore across the entire injection zone at a minimum.

DIVERTER

Diverting agents can be used to cause the acid to disperse as evenly as practical over the injection interval in an attempt to remove the majority of damage. Diverting agents typically consist of water soluble benzoic acid flakes in a gelled HEC polymer and ammonium chloride (NH_4Cl) carrier. Rock salt can also be used as a diverting agent but care must be taken to avoid contact with other chemicals downhole to prevent secondary formation of insoluble materials.

SPACER AND POST FLUSH

Fluid spacers are sometimes required to maintain separation of various treatment chemicals as they are being pumped into the well. Certain treatment chemicals are incompatible and may cause secondary precipitates. The fluid is also used to displace the treatment chemicals from the downhole piping out into the injection zone. This fluid usually consists of 3% ammonium chloride water with clay swelling inhibitor added.

ADDITIVES

Care is taken to ensure that all additives are completely compatible with each other and the acids. Because the time from acid mixing at the plant to acid pumping on location can be delayed, fluid transports are usually capable of continuous mixing at the job site.

Corrosion Inhibitor - The treatment acids are corrosive to the steel pipes in the wellbore. All acids are inhibited to reduce the amount of metal loss to 0.02 lb/sq ft for the entire time of the acid job. Alkyl Ammonium chloride is typically used for this purpose. Arsenic should not to be used for this purpose.

Surfactant - Surfactants are required to demulsify the acids and formation fluids (organic amines and salts of quaternary amines or polyxyethlated alkylphenols are typically used). Surfactants are also used to reduce the interfacial tension of the fluids (by use of alkylaryl sulfonate or ethoxylated alkylphenol at a concentration of 0.1 to 0.5 percent by volume). Another important function of surfactants is to maintain a water-wet state in the formation and prevent sludge formation (surface active chemicals such as alkylphenols and fatty acids). Maintaining a water wet state of the injection zone increases the ability to inject waste water.

Complexing Agent (Iron Sequestrant) - This is required to prevent the precipitation of gelatinous ferric hydroxide. An organic acid derivative EDTA (ethylene diamine tetracetic acid) is usually used. The agent is designed to hold 1,300 to 1,500 mg/l of iron in a 15% HCl acid solution. Citric acid is also sometimes used for this purpose.

Clay Inhibitor - Clay inhibitor is used to reduce the potential for injectivity reduction caused by injection zone clay swelling from the invasion of foreign water. A multi-nuclei organic polymer is usually used.

Mutual Solvent - These solvents are used to reduce the potential for formation of solids stabilized emulsions during and after the acid pumping. A 5% by volume EGMBE (ethylene glycol monobutyl ether) is typically used.

Xylene – Xylene is used to remove oil and other hydrocarbon deposits from the wellbore and the injection zone. The xylene is typically dispersed in the 15% HCl acid at a concentration of approximately 10%.